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Analysis of the Costs and Cost Effectiveness of Allowing SO2 Emission Credits for Cogeneration Systems

Radian Corp., Research Triangle Park, NC

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16. ABSTRACT

This document discusses the results of a cost analysis that was performed to assess the reasonableness of emission credits for cogeneration facilities under new source performance standards limiting SO_2 emissions from industrial-commercial-institutional steam generating units. Emission credits would allow a cogeneration system to achieve a lower percent reduction in emissions or to meet a higher emission limit in proportion to the increased overall efficiency achieved by the cogeneration system. The analysis examined two common types of cogeneration, steam generator-based and combined cycle systems, and analyzed the incremental cost effectiveness of not providing emission credits versus providing emission credits for two regulatory alternatives: standards based on the use of low sulfur fuels and standards requiring a percent reduction in SO_2 emissions.

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Emission Standards and Engineering Division
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EXECUTIVE SUMMARY

A cost analysis was performed to assess the reasonableness of emission credits for cogeneration facilities under new source performance standards being developed to limit sulfur dioxide (SO_2) emissions from industrial-commercial-institutional steam generating units with heat input capacities of greater than 100 million Btu/hour. This analysis examined two common types of cogeneration, steam generator-based cogeneration and combined cycle systems. The results of this analysis can be applied to all types of cogeneration units.

This analysis considers two SO_2 regulatory alternatives:

1) Standards based on the use of low sulfur fuels.
2) Standards requiring a percent reduction in SO_2 emissions based on the use of flue gas desulfurization systems.

The results of this analysis show that the average cost effectiveness of standards based on low sulfur fuels for coal-fired steam generator-based cogeneration units is less than $420/ton in all cases. The average cost effectiveness of standards requiring a percent reduction in SO_2 emissions is less than $640/ton. The incremental cost effectiveness of not including an emission credit in standards based on the use of low sulfur fuels for coal-fired steam generator-based cogeneration units varies from $556/ton in Region V to $83/ton in Region VIII. The incremental cost effectiveness of not including an emission credit in standards requiring a percent reduction in SO_2 emissions for coal-fired steam generator-based cogeneration systems varies from $273/ton in Region V to $500/ton in Region VIII.

For oil-fired steam generator-based cogeneration units, the average cost effectiveness of standards based on low sulfur fuels is less than $510/ton. The average cost effectiveness of standards requiring a percent reduction in SO_2 emissions is less than $460/ton. The incremental cost effectiveness of not including an emission credit in standards based on the use of low sulfur fuels for oil-fired steam generator-based cogeneration

units is $581/ton. The incremental cost effectiveness of not including an emission credit in standards requiring a percent reduction in SO_2 emissions is $167/ton. These results are generally representative of oil-fired steam generator-based cogeneration systems in all ten EPA regions.

The analysis of fully-fired coal combined cycle cogeneration units shows that the average cost effectiveness of standards based on low sulfur fuels is less than $413/ton in all cases. The average cost effectiveness of standards requiring a percent reduction in SO_2 emissions is less than $741/ton. The incremental cost effectiveness of not including an emission credit in standards based on the use of low sulfur fuels for coal-fired combined cycle cogeneration units varies from $550/ton in Region V to $0/ton in Region VIII. The incremental cost effectiveness of not including an emission credit in standards requiring a percent reduction in SO_2 emissions varies from $250/ton in Region V to $1000/ton in Region VIII.

For oil-fired combined cycle cogeneration units, the average cost effectiveness of standards based on low sulfur fuels is less than $640/ton. The average cost effectiveness of standards requiring a percent reduction in SO_2 emissions is less than $1000/ton. The incremental cost effectiveness of not including an emission credit in standards based on the use of low sulfur fuels for oil-fired combined cycle cogeneration units is $968/ton for fully-fired systems and $640/ton for supplementary-fired systems. The incremental cost effectiveness of not including an emission credit in standards requiring a percent reduction in SO_2 emissions is $333/ton for fully-fired systems and $292/ton for supplementary-fired systems. These results are generally representative of oil-fired combined cycle cogeneration systems in all ten EPA regions.

1.0 INTRODUCTION

This cost and cost effectiveness analysis was undertaken in conjunction with efforts to develop sulfur dioxide (SO_2) new source performance standards for industrial-commercial-institutional steam generating units with heat input capacities greater than 100 million Btu/hr. In addition to conventional systems for industrial steam generation, the analysis of new source performance standards for SO_2 emissions control must also consider other systems for steam generation that are currently being used in industry and which are potential sources of SO_2 emissions. Cogeneration systems are one such set of systems and the evaluation of the impacts of alternative SO_2 emission control standards on these systems is the subject of this report.

Cogeneration Systems

Cogeneration systems are defined as energy systems that simultaneously produce both electrical (or mechanical) energy and thermal energy from the same primary energy source. Cogeneration systems are efficient electric/thermal energy production technologies with a potential for local and regional energy savings and emission reductions.

Following adoption of the Public Utility Regulatory Policies Act of 1978 (PURPA), there has been increasing interest in the cogeneration of electricity at industrial, commercial, and institutional sites. Under PURPA, qualifying cogenerators can sell their excess electrical power directly to electric utility companies who are obligated to purchase the power at the utilities' avoided cost, making on-site cogeneration economically attractive in many cases.

There are two general types of cogeneration systems currently in industrial use: steam generator-based systems and combined cycle (or gas turbine-based) cogeneration systems. Both systems are considered in this report and the differences between them are explained in detail below. Both systems are efficient generators of electrical energy and steam, and generally operate at a higher overall thermal efficiency than either an

electric power plant or an industrial steam generating unit alone. As a result, to generate equivalent amounts of electrical and thermal energy, the total fuel used by a cogeneration facility would be less than the combined total of fuel used at an utility steam generating unit to generate electricity and the fuel used at an industrial steam generating unit to generate steam for space heat or process needs.

Emission Credits

The potential for regional energy savings through the use of a cogeneration system, compared to the use of separate steam generating units for electric power generation and industrial steam production, can range from 5 percent to almost 30 percent depending on the specific industry using the cogeneration system and the type of fuel used. This reduced regional fuel consumption can translate into regional air pollution emission reductions under certain conditions. For example, if a cogeneration system reduces regional fuel use by 15 percent and displaces a utility steam generating unit firing the same fuel and subject to the same emission limitation, regional emissions would be similarly reduced by 15 percent.

Because of this emission reduction potential, it has been suggested that new source performance standards for industrial-commercial-institutional steam generating units should include some type of "emission credit" for the higher efficiencies achieved by cogeneration systems. Such a credit, according to its proponents, would reduce the cost of air pollution control at a cogeneration site, result in equivalent regional emissions, and encourage the use of cogeneration systems.

If an emission credit were allowed for cogeneration systems, it would adjust increase the emission limitation for cogeneration steam generating units, offsetting any regional emission reduction that might occur from the use of the cogeneration system. For example, for a coal-fired steam generating unit subject to an SO_2 emission limit of 516 ng/J (1.2 lb/million Btu) heat input, a 15 percent emission credit reflecting the potential decrease in regional emissions would increase the emission limit to 593 ng/J

(1.38 lb/million Btu) heat input. Similarly, for a coal-fired steam generating unit subject to a percent reduction requirement of 70 or 90 percent, a 15 percent emissions credit would decrease the percent reduction requirement to 65.5 or 88.5 percent, respectively.

It may be quite difficult, however, to identify the appropriate emission credit for specific cogeneration systems. In cases where different emission standards are applicable to the displaced fuel fired in a utility steam generating unit and the fuel fired in the cogeneration system, or where different fuels are fired in the utility steam generating unit than in the cogeneration system, the environmental and fuel use impacts of cogeneration become less clear. Where a new cogeneration system achieves emission levels that are lower than those from the utility steam generating units, a 15 percent regional energy savings may result in more than a 15 percent reduction in regional emissions. Conversely, if the cogeneration system results in emissions higher than the utility steam generating unit, a 15 percent regional energy savings may result in less than a 15 percent emission reduction. If hydroelectric or nuclear power generation capacity is being replaced by cogeneration, regional emissions would increase. Also of importance to local emissions is the fact that a larger industrial-commercial-institutional steam generating unit is used in the cogeneration system than would otherwise be used. Consequently, local emissions at the cogeneration site increase in all cases.

To assess the reasonableness of emission credits for cogeneration systems, the cost effectiveness of SO_2 emission control associated with not providing emission credits was examined. This analysis compared the cost effectiveness of SO_2 control among a conventional industrial-commercial-institutional steam generating unit, a cogeneration steam generating unit without emission credits, and a cogeneration steam generating unit with emission credits, and calculated the incremental cost effectiveness of not providing emission credits.

Report Outline

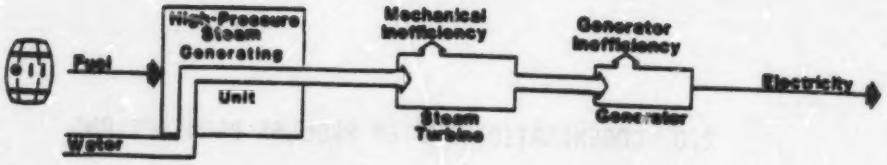
Detailed descriptions of the operation of both steam generator-based and combined cycle cogeneration systems are presented in Section 2. Section 3 discusses the rationale for emission credits and shows how the credits were calculated for this analysis. Section 4 presents the cost and cost effectiveness results of the study. Appendix A contains 8 model cases for combined cycle cogeneration systems and Appendix B contains sample calculations.

2.0 COGENERATION SYSTEM PROCESS DESCRIPTIONS

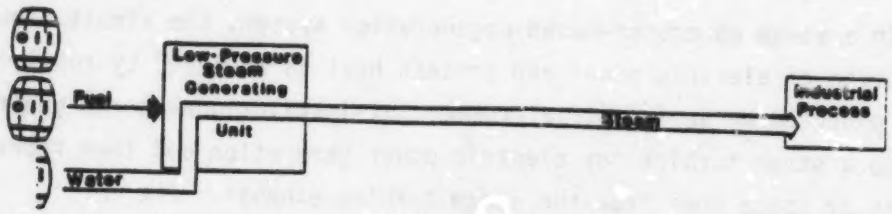
Steam Generator-Based Cogeneration System

In a steam generator-based cogeneration system, the simultaneous production of electric power and process heat is achieved by supplying the steam produced by an industrial-commercial-institutional steam generating unit to a steam turbine for electric power generation and then recovering process or space heat from the steam turbine exhaust. The industrial-commercial-institutional steam generating unit used for an on-site cogeneration system would be small enough that the total fuel use during cogeneration would be less than the combined total of the fuel used at a utility steam generating unit to generate electricity and the fuel used at an industrial steam generating unit to generate steam for space heat and process needs.

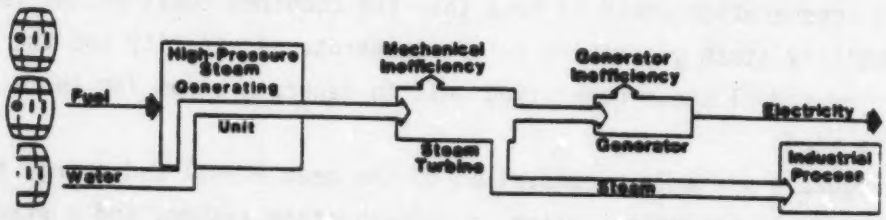
Figure 1 presents a comparison of the heat inputs and energy inputs for an electrical generating system, a process-steam system, and a steam generator-based cogeneration system. This figure shows that the steam generator-based cogeneration consumes approximately 15 percent less fuel to produce the same amount of energy as the electrical and steam generating units combined. Since part of the heat input to a cogeneration steam generating unit is consumed to generate electricity, a steam generator-based cogeneration system will have to fire 15 to 25 percent more fuel than a conventional steam generating unit to produce the same amount of steam. For example, as shown in Figure 1, if the conventional steam generating unit fires 150 million Btu per hour, then a steam generating unit based cogeneration system would fire 183 million Btu per hour (150 million Btu/hr * [2.75 barrel/2.25 barrel] = 183 million Btu/hr) to produce equivalent amounts of steam.



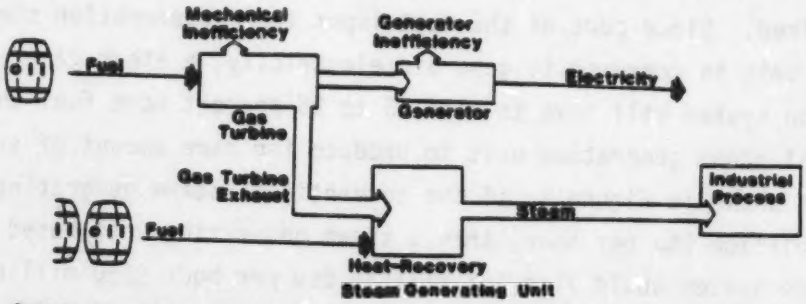
(A) Conventional electrical generating system requires the equivalent of 1 barrel of oil to produce 600 kWh electricity.



(B) Conventional process-system requires the equivalent of 2-1/4 barrels of oil to produce 8,500 lb of process steam.



(C) Steam generating unit cogeneration system requires the equivalent of 2-3/4 barrels of oil to generate the same amount of energy as systems A and B combined.



(D) Combined cycle cogeneration system requires the equivalent of 2-1/2 barrels of oil to generate the same amount of energy as systems A and B combined.

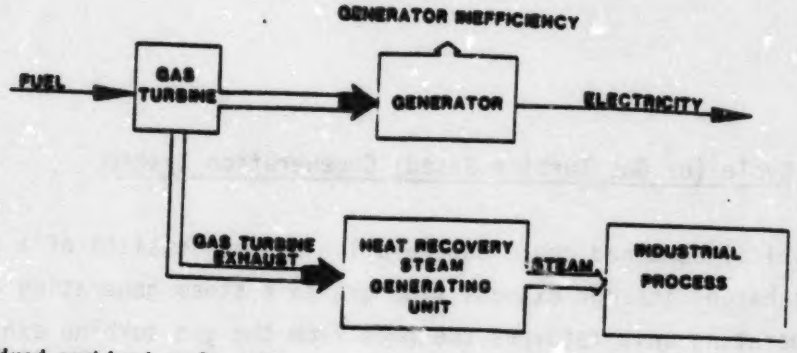
Figure 1. Conventional electrical and process steam systems compared with steam generator-based and combined cycle cogeneration systems.

Combined Cycle (or Gas Turbine-Based) Cogeneration System

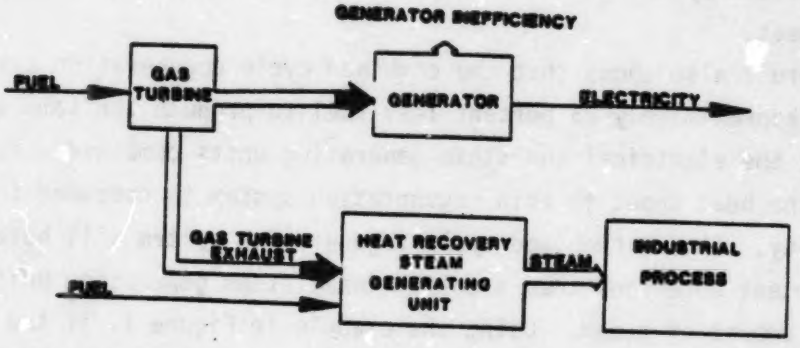
A typical combined cycle cogeneration system consists of a gas turbine which discharges its hot exhaust flue gas to a steam generating unit. The steam generating unit recovers the heat from the gas turbine exhaust. In industrial applications, the shaft power produced by the gas turbine is used for direct mechanical drive (including electric power generation) and the steam produced by the heat recovery steam generating unit is used for process heat.

Figure 1 also shows that the combined cycle cogeneration system consumes approximately 23 percent less fuel to produce the same amount of energy as the electrical and steam generating units combined. As before, part of the heat input to this cogeneration system is consumed to generate electricity. Thus a combined cycle cogeneration system will have to fire 10 to 40 percent more fuel than a conventional steam generating unit to produce the same amount of steam. Using the example in Figure 1, if the conventional unit fires 150 million Btu/hr, then a combined cycle cogeneration system would fire 167 million Btu/hr (150 million Btu/hr * [2.50 barrel/2.25 barrel] = 167 million Btu/hr) to produce equivalent amounts of steam.

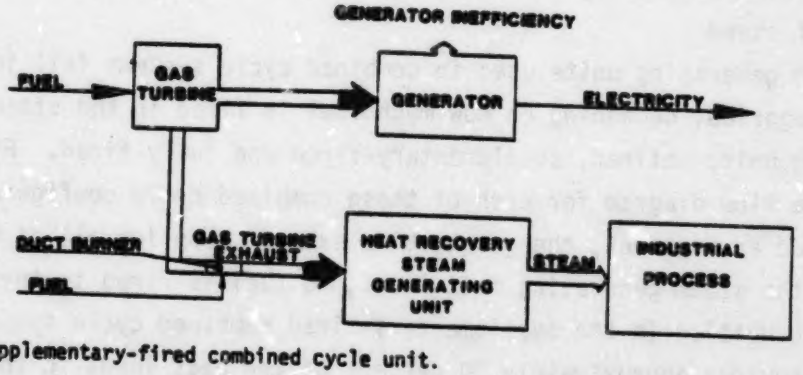
Steam generating units used in combined cycle systems fall into one of three categories, depending on how much fuel is fired in the steam generating unit: unfired, supplementary-fired and fully-fired. Figure 2 presents a flow diagram for each of these combined cycle configurations. In the unfired arrangement, the gas turbine exhaust supplies all of the heat input to the steam generating unit (i.e., no fuel is fired in the steam generating unit). In the supplementary-fired combined cycle system, the gas turbine provides approximately 70 percent of the heat input to the steam generating unit, with the remaining 30 percent being supplied by the fuel fired in the steam generating unit. For a fully-fired arrangement, the gas turbine exhaust provides approximately 25 percent of the heat input to the steam generating unit, with the remaining 75 percent being supplied by fuel fired in the steam generating unit.



(A) Unfired combined cycle unit.



(B) Fully-fired combined cycle unit.



(C) Supplementary-fired combined cycle unit.

Figure 2. Combined Cycle Cogeneration Systems.

The heat recovery steam generating unit in unfired and supplementary-fired combined cycle systems is typically a modular finned-tube heat exchanger. In the unfired arrangement, the gas turbine exhaust is supplied directly to the finned-tube heat exchanger. For the supplementary-fired arrangement, a limited amount of fuel is combusted in a grid burner in the turbine exhaust duct to raise the temperature of the exhaust gases before they reach the heat exchanger. Finned-tube heat exchangers are limited to gas inlet temperatures of approximately 1400°F. Thus the amount of supplementary fuel that can be fired is limited. Also, because of potential fouling problems, only "clean" fuels such as natural gas or oil can be used in supplementary-fired combined cycle systems.

In a fully-fired combined cycle system, the heat recovery steam generating unit is a conventional water-wall steam generating unit and the gas turbine exhaust is used to provide preheated combustion air to the steam generating unit. The term "fully-fired" indicates that the steam generating unit uses all the available oxygen in the gas turbine exhaust for combustion. Fully-fired combined cycle systems can theoretically fire coal, oil, or natural gas. However, coal has not been used as a fuel in the steam generating unit of combined cycle systems because natural gas and oil-fired steam generating units have lower capital costs and they are less complicated, easier to operate, and require less maintenance than an equivalent sized coal-fired steam generating unit.

In summary, the current generation of combined cycle systems fire gaseous or liquid fuels in both the gas turbine and the steam generating unit. At this time, coal is not used in combined cycle systems. However, coal-firing in the steam generating unit of a fully-fired combined cycle system may become a viable option.

3.0 EMISSION CREDITS

As discussed in Section 1.0, cogeneration can potentially reduce regional energy consumption by 5 to almost 30 percent depending on the specific industry using the cogeneration system and the type of fuel fired. This reduced fuel consumption could translate into regional air pollution emission reductions. For example, if a cogeneration system reduces fuel use by 15 percent and displaces a utility steam generating unit firing the same fuel and subject to the same emission limitations, regional air pollution emissions would similarly be reduced by 15 percent.

Because of this emission reduction potential, the question has been raised as to whether new source performance standards for industrial-commercial-institutional steam generating units should include some type of "emission credit" for the higher efficiencies achieved by cogeneration systems. An emission credit would reduce the annualized cost of control of a cogeneration steam generating unit. However, if an emission credit is granted for cogeneration systems, it would increase the emission limitation for cogeneration steam generating units, offsetting any regional emission reduction that might occur from the use of a cogeneration system.

Table 1 illustrates how an emission credit for cogeneration systems could be incorporated into standards based on the use of low sulfur fuel or standards requiring a percent reduction in emissions. As shown in this table, if standards for steam generating units based on the use of low sulfur fuel limited SO_2 emissions to 1.2 lb/million Btu heat input for coal-fired units and to 0.8 lb/million Btu heat input for oil-fired units, a 30 percent cogeneration emission credit would increase these emission limits to 1.56 lb/million Btu and 1.04 lb/million Btu heat input, respectively.

Fuel pricing data are not available for low sulfur fuels that could meet emission levels of 1.56 lb/million Btu heat input for coal and 1.04 lb/million Btu heat input for oil. Pricing data are available, however, for low sulfur fuels capable of meeting an emission limit of 1.7 lb/million Btu and 1.6 lb/million Btu heat input for coal and oil, respectively. Thus, this analysis assumed a cogeneration emission credit of 42 percent for

TABLE 1. CALCULATION OF STEAM GENERATOR-BASED COGENERATION EMISSION CREDIT

A. For a standard based on the use of low sulfur fuel (e.g., 1.2 lb/million Btu) an emission credit would allow the steam generating unit operator to burn a higher sulfur fuel.

SO_2 Emission Limit = 1.2 lb/million Btu

Cogeneration Steam Generating Unit SO_2 Emission Limit with 30 Percent Emission Credit = 1.2 lb/million Btu x 1.3/1.0 = 1.56 lb/million Btu

B. For a standard requiring a specific percent reduction (e.g., 90 percent), an emission credit would allow the steam generating unit to operate its flue gas desulfurization system at a lower percent removal.

SO_2 Percent Reduction Requirement = 90 Percent

SO_2 Emissions Permitted = 100 Percent - 90 Percent = 10 Percent

Cogeneration Steam Generating Unit SO_2 Emission Limit with 30 Percent Emission Credit: 10 Percent x 1.3/1.0 = 13 Percent

Cogeneration Steam Generating Unit SO_2 Percent Reduction Requirement with 30 Percent Emission Credit = 100 Percent - 13 Percent = 87 Percent.

coal-fired steam generating units and 100 percent for oil-fired steam generating units in order to use available fuel pricing data.

For a standard requiring a 90 percent reduction in SO_2 emissions from steam generating units, a 30 percent cogeneration emission credit reduces this percent reduction requirement to 87 percent. Thus, percent reduction requirements of 90 and 87 percent were examined to determine whether an emission credit for cogeneration systems under standards requiring a percent reduction in SO_2 emissions is reasonable.

Combined Cycle Cogeneration Systems

Table 2 demonstrates how an emission credit for combined cycle cogeneration systems could be incorporated into standards based on the use of low sulfur fuel or standards requiring a percent reduction in SO_2 emissions for steam generating units. The magnitude of the cogeneration emission credit is determined by dividing the total heat input (steam generating unit fuel + gas turbine exhaust) into the steam generating unit by the heat input of the fuel fired in the steam generating unit. For fully-fired combined cycle systems, the resulting emission credit is in the range of 30 to 35 percent, depending on whether coal or oil is fired in the steam generating unit. For supplementary-fired combined cycle systems, the emission credit is around 210 percent, since most of the heat input to the steam generating unit is provided by the gas turbine exhaust.

As discussed earlier in the steam generator-based cogeneration section, the cogeneration emission credit was increased in several cases to reflect available fuel pricing data. As a result, for standards based on the use of low sulfur fuel, the combined cycle cogeneration analysis assumed emission credits of:

1) 42 percent for fully-fired coal combined cycle steam generating units (i.e., 1.7 lb/million Btu emission limit),

TABLE 2. CALCULATION OF COMBINED CYCLE COGENERATION EMISSION CREDIT

A. For a standard based on the use of low sulfur coal, (e.g., 1.2 lb/million Btu) an emission credit would allow the steam generating unit to fire a higher sulfur coal.

SO_2 Emission Ceiling = 1.2 lb/million Btu

SO_2 Emission Limit With Emission Credit =

$$1.2 \text{ lb/million Btu} \times \left(\frac{\text{Total Heat Input}}{\text{Steam Generating Unit Fuel Heat Input}} \right)$$

where Total Heat Input = Steam Generating Unit Fuel Heat Input + Gas Turbine Exhaust Heat Input

Example: For a combined cycle cogeneration unit with a steam generating unit fuel heat input of 100 million Btu/hour and a gas turbine exhaust heat input of 37 million Btu/hour,

SO_2 Emission Limit with Emission Credit =

$$1.2 \text{ lb/million Btu} \times \frac{137 \text{ million Btu/hr}}{100 \text{ million Btu/hr}} = 1.64 \text{ lb/million Btu}$$

B. For a standard requiring a percent reduction in SO_2 emissions, (e.g., 90 percent) an emission credit would allow the steam generating unit to operate the flue gas desulfurization system at a lower percent removal.

SO_2 Percent Reduction Requirement Without Emission Credit = 90 percent

SO_2 Emissions Level Permitted = 100-90 = 10 percent

SO_2 Percent Reduction Requirement with Emission Credit =

$$100 - \left[10 \text{ Percent} \times \frac{\text{Total Heat Input}}{\text{Steam Generating Unit Fuel Heat Input}}\right]$$

where Total Heat Input = Steam Generating Unit Fuel Heat Input + Gas Turbine Exhaust Heat Input

Example: For a combined cycle cogeneration unit with a steam generating unit fuel heat input of 100 million Btu/hour and a gas turbine exhaust heat input of 37 million Btu/hour,

Percent Reduction Requirement With Emission Credit =

$$100 \text{ Percent} - \left[10 \text{ Percent} \times \frac{137 \text{ million Btu/hr}}{100 \text{ million Btu/hr}}\right] = 86 \text{ percent}$$

2) 100 percent for fully-fired oil combined cycle steam generating units (i.e., 1.6 lb/million Btu emission limit), and

3) 275 percent for supplementary-fired oil combined cycle steam generating units (i.e., 3.0 lb/million Btu emission limit).

For standards requiring a percent reduction in SO_2 emissions, the emission credits examined were:

1) 40 percent for fully-fired coal combined cycle steam generating units (i.e., 86 percent SO_2 reduction),

2) 30 percent for fully-fired oil combined cycle steam generating units (i.e., 87 percent SO_2 reduction), and

3) 215 percent for supplementary-fired oil combined cycle steam generating units (i.e., 69 percent SO_2 reduction).

4.0 COST ANALYSIS

This analysis examines the reasonableness of emission credits for cogeneration facilities under two regulatory alternatives for SO_2 new source performance standards:

1) Standards based on the use of low sulfur fuels.

2) Standards requiring a percent reduction in SO_2 emissions based on the use of flue gas desulfurization systems.

All costs presented in this analysis are in January 1983 dollars and all flue gas desulfurization costs are based on sodium scrubbing technology. Information obtained on paper, chemical, and petroleum refining industry cogeneration systems show that these facilities usually operate at an annual capacity factor of about 0.9.[1] Consequently, an annual capacity factor of 0.9 was assumed in this analysis.

Regions V and VIII were selected for analysis of the coal-fired cogeneration steam generating units in this report - Region V because coal prices in that region are considered representative of those in the majority of the regions, and Region VIII because it has significantly lower coal prices than any other region.[2] Oil-fired cogeneration steam generating units were examined for Region V only because the premium price for a low sulfur oil compared to a high sulfur oil is essentially constant for all regions.[2] Table 3 presents the regional coal and oil prices for all ten EPA regions.

4.1 Steam Generator-Based Cogeneration Systems

Coal-Fired Steam Generating Units

Tables 4 and 5 present the results of this analysis for coal-fired cogeneration steam generating units in Regions V and VIII, respectively. As

TABLE 3. REGIONAL FUEL PRICES IN $/MILLION BTU (JANUARY 1983 $)[a,b,c]

Fuel Type	Sulfur Content (lb $SO_2/10^6$ Btu)[d]	REGION I	II	III	IV	V	VI	VII	VIII	IX	X
COAL											
Bituminous											
B	0.80 - 1.08	3.76	3.52	3.14	3.19	3.32	3.34	3.14	1.99	2.80	3.18
D	1.08 - 1.67	3.71	3.45	2.94	2.98	3.18	3.21	3.08	1.86	2.82	2.97
E	1.67 - 2.50	3.65	3.30	2.85	2.96	3.08	3.20	3.04	1.87	2.77	2.84
F	2.50 - 3.33	3.46	3.13	2.75	2.88	2.93	3.19	2.92	-	-	-
G	3.33 - 5.0	3.16	2.82	2.42	2.60	2.67	3.09	2.62	-	-	-
H	>5.00	3.26	2.85	2.39	2.62	2.50	2.96	2.47	-	-	-
Subbituminous											
B	0.80 - 1.08	-	-	-	-	3.38	3.49	2.74	1.40	2.84	2.66
D	1.08 - 1.67	-	-	-	-	3.34	3.39	2.69	1.39	2.74	2.60
E	1.67 - 2.50	-	-	-	-	3.30	3.32	2.72	1.28	2.65	2.09
RESIDUAL OIL											
0.8 lb $SO_2/10^6$ BTU[e]	0.80	5.50	5.49	5.49	5.46	5.63	5.49	5.60	5.29	5.11	5.07
NATURAL GAS	-	5.83	5.79	5.73	6.02	5.88	5.41	5.45	4.91	5.44	5.57

[a] Reference 2.

[b] 1990 levelized fuel prices in January 1983 dollars.

[c] To convert $/$10^6$ Btu to $/kJ, multiply by 0.947.

[d] To convert lb/10^6 Btu to ng/J, multiply by 430.

[e] Subtract $0.69/$10^6$ Btu for 3.0 lb $SO_2/10^6$ Btu oil; subtract $0.36/$10^6$ Btu for 1.6 lb $SO_2/10^6$ Btu oil; add $0.34/$10^6$ Btu for 0.3 lb $SO_2/10^6$ Btu oil.

TABLE 4. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COGENERATION COAL-FIRED STEAM GENERATING UNITS IN REGION V[a]

Steam Generating Unit	Fuel Type,[f] (lb SO_2/million Btu)	Annualized Costs, $1000/yr	Annual Emissions, (tpy)	Average Cost Effectiveness,[b] ($/ton)	Incremental Cost Effectiveness,[c] ($/ton)
Conventional Unit (150 million Btu/hr)					
Regulatory Baseline (2.5 lb/million Btu)	2.10	8,710	1,240	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95	8,990	560	412	-
Percent Reduction (90 Percent)	5.54	9,260	250	556	871
Cogeneration Unit W/O Credit (180 million Btu/hr)					
Regulatory Baseline (2.5 lb/million Btu)	2.10	10,088	1,490	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95	10,430	670	417	-
Percent Reduction (90 Percent)	5.54	10,720	300	531	784
Cogeneration Unit W/Credit (180 million Btu/hr)					
Regulatory Baseline (2.5 lb/million Btu)	2.10	10,088	1,490	-	-
Low Sulfur Fuel (1.7 lb/million Btu)[d]	1.45	10,230	1,030	309	-
Percent Reduction (87 Percent)[e]	5.54	10,690	410	558	742

[a]Based on a capacity factor of 0.9.

[b]Compared to regulatory baseline.

[c]Compared to less stringent alternative.

[d]With a 30 percent emission credit, a low sulfur coal emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu) would increase to 671 ng SO_2/J (1.56 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 42 percent in order to use available pricing data for a coal meeting a 731 ng SO_2/J (1.7 lb SO_2/million Btu) emission limit.

[e]Based on a 30 percent emission credit.

[f]Average uncontrolled SO_2 emissions.

TABLE 5. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COGENERATION COAL-FIRED STEAM GENERATING UNITS IN REGION VIII[a]

Steam Generating Unit	Fuel Type,[f] (lb SO_2/million Btu)	Annualized Costs, $1000/yr	Annual Emissions, (tpy)	Average Cost Effectiveness,[b] ($/ton)	Incremental Cost Effectiveness,[c] ($/ton)
Conventional Unit (150 million Btu/hr)					
Regulatory Baseline (2.5 lb/million Btu)	2.10	6,710	1,240	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95	6,860	560	221	-
Percent Reduction (90 Percent)	0.95	7,480	40	642	1,192
Cogeneration Unit W/O Credit (180 million Btu/hr)					
Regulatory Baseline (2.5 lb/million Btu)	2.10	7,680	1,490	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95	7,860	670	220	-
Percent Reduction (90 Percent)	0.95	8,570	50	618	1,145
Cogeneration Unit W/Credit (180 million Btu/hr)					
Regulatory Baseline (2.5 lb/million Btu)	2.10	7,680	1,490	-	-
Low Sulfur Fuel (1.7 lb/million Btu)[d]	1.45	7,830	1,030	326	-
Percent Reduction (87 Percent)[e]	0.95	8,560	70	620	760

[a]Based on a capacity factor of 0.9.

[b]Compared to regulatory baseline.

[c]Compared to less stringent alternative.

[d]With a 30 percent emission credit, a low sulfur coal emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu) would increase to 671 ng SO_2/J (1.56 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 42 percent in order to use available pricing data for a coal meeting a 731 ng SO_2/J (1.7 lb SO_2/million Btu) emission limit.

[e]Based on a 30 percent emission credit.

[f]Average uncontrolled SO_2 emissions.

shown, the cost effectiveness of SO_2 control for standards based on the use of low sulfur coal are similar for a conventional steam generating unit, a cogeneration steam generating unit without an emission credit, and a cogeneration unit with an emission credit. For example, the average cost effectiveness of SO_2 emission control in Region V is $412/ton for a conventional steam generating unit; $417/ton for a cogeneration unit without an emission credit; and $309/ton for a cogeneration unit with an emission credit. Similarly, in Region VIII the average cost effectiveness of emission control is $221/ton for a conventional steam generating unit; $220/ton for a cogeneration unit without an emission credit; and $326/ton for a cogeneration unit with an emission credit.

The same is true for the cost effectiveness of SO_2 control for standards requiring a percent reduction in emissions from coal-fired steam generating units. The incremental cost effectiveness of SO_2 emission control associated with standards requiring a percent reduction in emissions over standards based on the use of low sulfur fuels in Region V is $871/ton for a conventional steam generating unit; $784/ton for a cogeneration unit without an emission credit; and $742/ton for a cogeneration unit with an emission credit. Similarly, in Region VIII the incremental cost effectiveness of emission control is $1,192/ton for a conventional steam generating unit; $1,145/ton for a cogeneration unit without an emission credit; and $760/ton for a cogeneration unit with an emission credit.

The significant reduction in the incremental cost effectiveness of emission control for standards requiring a percent reduction in Region VIII for a cogeneration steam generating unit with an emission credit compared to the incremental cost effectiveness without an emission credit is due to price differentials between coals fired under the low sulfur coal alternative. The emission credit would permit the firing of a higher sulfur and lower cost coal in the cogeneration steam generating unit. In Region VIII, the cost savings achieved by firing a higher sulfur coal are minor (approximately $30,000 per year) due to a small difference in price. The annual emissions, however, increase by some 360 tons per year. The lowering of the percent reduction requirement from 90 to 87 percent due to the

cogeneration emission credit results in a negligible reduction in costs and only a minor increase in emissions. As a result, the incremental emissions reduction of a percent reduction standard over a low sulfur coal standard is much greater for a cogeneration steam generating unit with an emissions credit than without an emissions credit, which translates to a significantly lower incremental cost effectiveness value.

In Region V, the annualized costs (i.e., fuel prices) and emissions vary in roughly the same proportion so that similar incremental cost effectiveness values are observed for cogeneration steam generating units with and without an emission credit.

As shown in Table 6, the incremental cost effectiveness of not providing emission credits with standards based on the use of low sulfur coal is $556/ton in Region V and $83/ton in Region VIII. Similarly, the incremental cost effectiveness of not providing emission credits with standards requiring a percent reduction in emission is only $273/ton in Region V and $500/ton in Region VIII.

Oil-Fired Steam Generating Units

Table 7 summarizes the cost effectiveness of SO_2 control for oil-fired steam generating units. As shown, for both conventional steam generating units and cogeneration steam generating units without emission credits, the lowest cost option to comply with a standard based on the use of low sulfur fuel is to purchase a high sulfur oil and use flue gas desulfurization. With a cogeneration emission credit, however, a higher sulfur and lower cost oil may be fired in the steam generating unit to meet a low sulfur fuel standard. In this case, it is less expensive to fire a low sulfur oil than to fire a high sulfur oil and use flue gas desulfurization.

For standards based on the use of low sulfur oil, the average cost effectiveness of SO_2 control for a conventional steam generating unit is $510/ton, compared with $494/ton for a cogeneration steam generating unit without an emission credit and $442/ton for a cogeneration steam generating unit with an emission credit.

TABLE 6. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING AN EMISSION CREDIT FOR COAL-FIRED COGENERATION STEAM GENERATING UNITS

	REGION V			REGION VIII		
	Annualized Cost $1000/yr	Annual Emissions, (tpy)	Incremental Cost Effectiveness ($/ton)	Annualized Cost $1000/yr	Annual Emissions, (tpy)	Incremental Cost Effectiveness ($/ton)
Low Sulfur Fuel Standard						
With Emission Credit (1.7 lb/10^6 Btu)	10,230	1,030	-	7,830	1,030	-
Without Emission Credit (1.2 lb/10^6 Btu)	10,430	670	556	7,860	670	83
Percent Reduction Standard						
With Emission Credit (87% FGD)	10,690	410	-	8,560	70	-
Without Emission Credit (90% FGD)	10,720	300	273	8,570	50	500

TABLE 7. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COGENERATION OIL-FIRED STEAM GENERATING UNITS[a]

Steam Generating Unit	Fuel Type,[b] (lb $SO_2/10^6$ Btu)	Annualized Costs, $1000/yr	Annual Emissions, (tpy)	Average Cost Effectiveness,[c] ($/ton)	Incremental Cost Effectiveness,[d] ($/ton)
Conventional Unit (150 million Btu/hr)					
Regulatory Baseline (3.0 lb/million Btu)	3.0	7,190	1,770	-	-
Low Sulfur Fuel (0.8 lb/million Btu)[e]	3.0/73% FGD	7,860	455	510	-
Percent Reduction (90 Percent)	3.0/90% FGD	7,940	135	459	250
Cogeneration Unit W/O Credit (180 million Btu/hr)					
Regulatory Baseline (3.0 lb/million Btu)	3.0	8,490	2,130	-	-
Low Sulfur Fuel (0.8 lb/million Btu)[e]	3.0/73% FGD	9,270	550	494	-
Percent Reduction (90 Percent)	3.0/90% FGD	9,360	160	442	231
Cogeneration Unit W/Credit (180 million Btu/hr)					
Regulatory Baseline (3.0 lb/million Btu)	3.0	8,490	2,130	-	-
Low Sulfur Fuel (1.6 lb/million Btu)[f]	1.6	8,930	1,135	442	-
Percent Reduction (87 Percent)[g]	3.0/87% FGD	9,350	220	450	459

[a]Assumes a capacity factor of 0.9.

[b]Average uncontrolled SO_2 emissions.

[c]Compared to regulatory baseline.

[d]Compared to less stringent alternative.

[e]It is less expensive to fire a high sulfur oil [1,291 ng SO_2/J (3 lb SO_2/million Btu)] and install an FGD system to achieve 73 percent reduction than to purchase a low sulfur oil [344 ng SO_2/J (0.8 lb SO_2/million Btu)].

[f]With a 30 percent emission credit, a low sulfur oil emission limit of 344 ng SO_2/J (0.8 lb SO_2/million Btu) would increase to 447 ng SO_2/J (1.04 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 100 percent in order to use available pricing data for a coal meeting a 688 ng SO_2/J (1.6 lb SO_2/million Btu) emission limit.

[g]Based on a 30 percent emission credit.

For standards requiring a percent reduction in SO_2 emissions, the incremental cost effectiveness of emission control over standards based on the use of low sulfur fuel is $250/ton for a conventional steam generating unit; $231/ton for a cogeneration unit without an emission credit; and $459/ton for a cogeneration unit with an emission credit.

As shown in Table 8, the incremental cost effectiveness of not providing emission credits is $581/ton for standards based on the use of low sulfur fuel and $167/ton for standards requiring a percent reduction in SO_2 emissions.

4.2 Combined Cycle Cogeneration Systems

Coal-Fired Steam Generating Units

Tables 9 and 10 present the cost effectiveness of SO_2 control for a fully-fired coal combined cycle steam generating unit in Regions V and VIII, respectively. For comparison, the cost effectiveness of SO_2 control for a conventional steam generating unit and a mixed fuel-fired steam generating unit (natural gas/coal) is also included. Mixed fuel-fired units are included in the analysis since, like combined cycle cogeneration units, a portion of the heat input to the steam generating unit comes from nonsulfur-bearing fuels (in this case natural gas). The annualized costs for mixed fuel-fired steam generating units are higher than those for other units in Tables 9 and 10 because the cost of natural gas has been included along with coal fuel costs. However, since natural gas does not contribute to SO_2 emissions and cost effectiveness values depend on cost differences between alternatives, the average and incremental cost effectiveness values cited in the tables are not influenced by the inclusion of natural gas costs.

It should also be noted that, for a percent reduction requirement in Region VIII, the fuel prices in this region are such that it is less expensive to fire a low sulfur coal and use flue gas desulfurization (FGD) than to fire a higher sulfur coal and apply an FGD system. This is because the delivered price of low sulfur subbituminous coal is well below the price

TABLE 8. INCREMENTAL COST EFFECTIVENESS OF WITHHOLDING EMISSION CREDITS FOR OIL-FIRED COGENERATION STEAM GENERATING UNITS

	Annualized Cost $1000/yr	Annual Emissions (tpy)	Incremental Cost[a] Effectiveness ($/ton)
Low Sulfur Fuel Standard			
With Emission Credit (1.6 lb/10^6 Btu)	8,930	1,135	-
Without Emission Credit (0.8 lb/10^6 Btu)	9,270[b]	550[b]	581
Percent Reduction Standard			
With Emission Credit (87% FGD/3.0 lb/10^6 Btu)	9,350	220	-
Without Emission Credit (90% FGD/3.0 lb/10^6 Btu)	9,360	160	167

[a]Compared to less stringent alternative.

[b]Based on firing a high sulfur oil [1,291 ng SO_2/J (3.0 lb SO_2/million Btu)] and using an FGD system to achieve 73 percent reduction.

TABLE 9. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR STANDARD BOILERS AND COMBINED CYCLE COAL-FIRED STEAM GENERATING UNITS IN REGION V[a]

Fully-Fired Coal

Steam Generating Unit	Fuel Type,[h] (lb SO_2/million Btu)	Steam Generating Unit Heat Input (10^6 Btu/hr)	Gas Turbine Exhaust Heat Input (10^6 Btu/hr)	Annualized Costs,[b] ($1000/yr)	Annual Emissions (tpy)	Average Cost Effectiveness ($/ton)[c]	Incremental Cost Effectiveness ($/ton)[d]
Conventional Unit (100 million Btu/hr)							
Regulatory Baseline (2.5 lb/million Btu)	2.10	100	-	2,430	830	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95			2,620	370	413	-
Percent Reduction (90 Percent)	5.54			2,850	170	636	1,150
Mixed Fuel Unit (137 million Btu/hr)							
Regulatory Baseline (2.5 lb/million Btu)	2.10/NG	137	-	4,140[g]	830	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95 NG			4,330[g]	370	413	-
Percent Reduction (90 Percent)	5.54 NG			4,590[g]	170	682	1,300
Combined Cycle Unit W/O Credit (137 million Btu/hr)							
Regulatory Baseline (2.5 lb/million Btu)	2.10	100	37	2,430	830	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95			2,620	370	413	-
Percent Reduction (90 Percent)	5.54			2,880	170	682	1,300
Combined Cycle Unit W/Credit (137 million Btu/hr)							
Regulatory Baseline (2.5 lb/million Btu)	2.10	100	37	2,430	830	-	-
Low Sulfur Fuel (1.7 lb/million Btu)[e]	1.45			2,510	570	308	-
Percent Reduction (86 Percent)[f]	5.54			2,860	250	741	1,094

[a]Based on a capacity factor of 0.9.

[b]Annual cost includes only the cost of fuel fired plus the annualized cost of SO_2 control device and does not include other steam generating unit annualized costs.

[c]Compared to regulatory baseline.

[d]Compared to less stringent alternative.

[e]Based on the heat input supplied by the gas turbine exhaust. Credit is calculated as 137/100, or 37 percent. This would translate into an emission limit of 706 ng SO_2/J (1.64 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 42 percent in order to use available pricing data for a coal meeting a 731 ng SO_2/J (1.7 lb SO_2/million Btu) emission limit.

[f]Based on a 40 percent emission credit.

[g]Annualized costs for mixed fuel-fired steam generating units are higher than those for other units examined because the cost of natural gas fuel has been included along with coal fuel costs.

[h]Average uncontrolled SO_2 emissions.

TABLE 10. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR STANDARD BOILERS AND COMBINED CYCLE COAL-FIRED STEAM GENERATING UNITS IN EPA REGION VIII[a]

Fully-Fired Coal

Steam Generating Unit	Fuel Type,[h] (lb SO_2/million Btu)	Steam Generating Unit Heat Input (10^6 Btu/hr)	Gas Turbine Exhaust Heat Input (10^6 Btu/hr)	Annualized Costs,[b] ($1000/yr)	Annual Emissions (tpy)	Average Cost Effectiveness ($/ton)[c]	Incremental Cost Effectiveness ($/ton)[d]
Conventional Unit (100 million Btu/hr)							
Regulatory Baseline (2.5 lb/million Btu)	2.10	100	-	1,101	830	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95			1,100	370	196	-
Percent Reduction (90 Percent)	0.95			1,570	30	700	1,382
Mixed Fuel Unit (137 million Btu/hr)							
Regulatory Baseline (2.5 lb/million Btu)	2.10/NG	137	-	2,440[g]	830	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95/NG			2,530[g]	370	196	-
Percent Reduction (90 Percent)	0.95/NG			3,020[g]	30	725	1,441
Combined Cycle Unit W/O Credit (137 million Btu/hr)							
Regulatory Baseline (2.5 lb/million Btu)	2.10	100	37	1,010	830	-	-
Low Sulfur Fuel (1.2 lb/million Btu)	0.95			1,100	370	196	-
Percent Reduction (90 Percent)	0.95			1,600	30	738	1,471
Combined Cycle Unit W/Credit (137 million Btu/hr)							
Regulatory Baseline (2.5 lb/million Btu)	2.10	100	37	1,010	830	-	-
Low Sulfur Fuel (1.7 lb/million Btu)[e]	1.45			1,100	570	346	-
Percent Reduction (86 Percent)[f]	0.95			1,590	40	734	924

[a]Based on a capacity factor of 0.9.

[b]Annual cost includes only the cost of fuel fired plus the annualized cost of SO_2 control device and does not include other steam generating unit annualized costs.

[c]Compared to regulatory baseline.

[d]Compared to less stringent alternative.

[e]Based on the heat input supplied by the gas turbine exhaust. Credit is calculated as 137/100, or 37 percent. This would translate into an emission limit of 706 ng SO_2/J (1.64 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 42 percent in order to use available pricing data for a coal meeting a 731 ng SO_2/J (1.7 lb SO_2/million Btu) emission limit.

[f]Based on a 40 percent emission credit.

[g]Annualized costs for mixed fuel-fired steam generating units are higher than those for other units examined because the cost of natural gas fuel has been included along with coal fuel costs.

[h]Average uncontrolled SO_2 emissions.

of higher sulfur bituminous coals. Although some higher sulfur content subbituminous coals are available in the region, the added operating and maintenance costs associated with the FGD system (due to higher sulfur loadings) outweigh the small price advantage these coals enjoy over low sulfur coal. This low sulfur subbituminous coal is the lowest cost fuel to fire in this region even when a percent reduction requirement is in force. In Region V, on the other hand, it is less expensive to fire a high sulfur coal and apply FGD to meet a percent reduction in emissions requirement.

As shown, the cost effectiveness of SO_2 control for standards based on the use of low sulfur coal are similar for a conventional steam generating unit, a mixed fuel-fired steam generating unit, a combined cycle cogeneration steam generating unit without an emission credit, and a combined cycle cogeneration steam generating unit with an emission credit. For example, the average cost effectivness of SO_2 emission control in Region V is $413/ton for a conventional steam generating unit; $413/ton for a mixed fuel-fired steam generating unit; $413/ton for a combined cycle cogeneration unit without an emission credit; and $308/ton for a combined cycle cogeneration unit with an emission credit. Similarly, in Region VIII the average cost effectiveness of emission control is $196/ton for a conventional steam generating unit; $196/ton for a mixed fuel-fired unit; $196/ton for a combined cycle cogeneration unit without an emission credit; and $346/ton for a combined cycle cogeneration unit with an emission credit.

The same is true for the cost effectiveness of SO_2 control for standards requiring a percent reduction in emissions from steam generating units. The incremental cost effectiveness of emission control associated with standards requiring a percent reduction in emissions over standards based on the use of low sulfur fuels in Region V is $1,150/ton for a conventional steam generating unit; $1,300/ton for a mixed fuel-fired unit; $1,300/ton for a combined cycle cogeneration unit without an emission credit; and $1,094/ton for a combined cycle cogeneration unit with an emission credit. Similarly, in Region VIII the incremental cost effectiveness of emission control is $1,382/ton for a conventional steam generating unit; $1,441/ton for a mixed fuel-fired unit; $1,471/ton for a

combined cycle cogeneration unit without an emission credit; and $924/ton for a combined cycle cogeneration unit with an emission credit.

As discussed previously under coal-fired steam generator-based cogeneration systems, the small fuel price differential in Region VIII between medium sulfur and low sulfur coals, gives rise to a significant difference in the average cost effectiveness values cited above for standards based on the use of the low sulfur fuel when comparing combined cycle cogeneration systems operating with and without an emissions credit. This fuel price behavior also explains the lower incremental cost effectiveness value for standards requiring a percent reduction in emissions over standards based on the use of low sulfur fuel in this region for combined cycle cogeneration units operating with an emission credit versus units operating without a credit.

As shown in Table 11, the incremental cost effectiveness of not providing emission credits with standards based on the use of low sulfur coal is $550/ton in Region V and $0/ton in Region VIII. Again, this difference is due entirely to the difference in fuel price between medium and low sulfur coal in these regions.

The incremental cost effectiveness of not providing emission credits with standards requiring a percent reduction in emissions is $250/ton in Region V and $1000/ton in Region VIII. Table 11 shows that there is very little difference in annualized costs for combined cycle cogeneration steam generating units meeting a percent reduction standard with an emission credit or without a credit. However, as noted above, combined cycle cogeneration units will fire high sulfur coal (5.54 lb/million Btu) in Region V to meet the percent reduction requirement and low sulfur coal (0.95 lb/million Btu) in Region VIII. The emission credit reduces the percent reduction requirement from 90 to 86 percent, or 4 percent. The difference in SO_2 emissions is minimal when applied to low sulfur coal in Region VIII but is magnified when applied to high sulfur coal in Region V. As a result, the emissions reduction between a standard percent requiring a reduction in emissions with an emissions credit and the same standard without a credit is much smaller in Region VIII than Region V. Since cost differences are

TABLE 11. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING AN EMISSION CREDIT FOR COMBINED CYCLE UNITS

Fully-Fired Coal

	REGION V			REGION VIII		
	Annualized Cost $1000/yr	Annual Emissions, (tpy)	Incremental Cost Effectiveness ($/ton)	Annualized Cost $1000/yr	Annual Emissions, (tpy)	Incremental Cost Effectiveness ($/ton)
Low Sulfur Fuel Standard						
With Emission Credit (1.7 lb/10^6 Btu)	2,510	570	-	1,100	570	-
Without Emission Credit (1.2 lb/10^6 Btu)	2,620	370	550	1,100	370	0
Percent Reduction Standard						
With Emission Credit (86% FGD)	2,860	250	-	1,590	40	-
Without Emission Credit (90% FGD)	2,880	170	250	1,600	30	1,000

roughly equal, the overall result is a higher incremental cost effectiveness value in Region VIII as compared to Region V.

Oil-Fired Units

Table 12 summarizes the cost effectiveness of SO_2 control for fully-fired and supplementary-fired oil-fired combined cycle systems and conventional oil-fired steam generating units. For standards based on the use of low sulfur fuels, the average cost effectiveness of SO_2 control is $640/ton for a conventional steam generating unit; $640/ton for a mixed fuel-fired steam generating unit; $640/ton for a fully-fired combined cycle steam generating unit without an emission credit; and $455/ton for a fully-fired combined cycle steam generating unit with an emission credit. For standards requiring a percent reduction in SO_2 emissions, the incremental cost effectiveness of SO_2 control over standards based on the use of low sulfur fuels is $44/ton for a conventional steam generating unit; $87/ton for a mixed fuel-fired steam generating unit; $130/ton for a fully-fired combined cycle steam generating unit without an emission credit; and $628/ton for a fully-fired combined cycle steam generating unit with an emission credit.

The cost effectiveness of SO_2 control is generally higher for supplementary-fired combined cycle steam generating units than for fully-fired combined cycle steam generating units, particularly in the case of standards requiring a percent reduction in SO_2 emissions, regardless of whether or not emission credits are provided. As shown in Table 12, for standards based on the use of low sulfur fuels the average cost effectiveness of SO_2 control is $640/ton for a mixed fuel-fired steam generating unit; $640/ton for a supplementary-fired combined cycle steam generating unit without an emission credit, and $0/ton for a supplementary-fired steam generating unit with an emission credit. With an emission credit, the credit is so large that no emission reduction is required beyond the regulatory baseline. As a result, the cost effectiveness is $0/ton.

TABLE 12. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COMBINED CYCLE OIL-FIRED STEAM GENERATING UNITS IN EPA REGION V[a]

Steam Generating Unit	Fuel Type,[b] (lb SO_2/million Btu)	Steam Generating Unit Heat Input (10^6 Btu/hr)	Gas Turbine Exhaust Heat Input (10^6 Btu/hr)	Annualized Costs,[c] ($1000/yr)	Annual Emissions (tpy)	Average Cost Effectiveness[d] ($/ton)	Incremental Cost Effectiveness[e] ($/ton)
Conventional Unit (100 million Btu/hr)							
Regulatory Baseline (3.0 lb/million Btu)	3.0	100	-	3,890	1,180	-	-
Low Sulfur Fuel (0.8 lb/million Btu)	0.8			4,440	320	640	-
Percent Reduction (90 Percent)	3.0/90% FGD			4,450	90	514	44
Fully-Fired							
Mixed Fuel Unit (129 million Btu/hr)							
Regulatory Baseline (3.0 lb/million Btu)	3.0/NG	129	-	5,240[j]	1,180	-	-
Low Sulfur Fuel (0.8 lb/million Btu)	0.8/NG			5,790[j]	320	640	-
Percent Reduction (90 Percent)	3.0/NG			5,810[j]	90	523	87
Combined Cycle Unit W/O Credit (129 million Btu/hr)							
Regulatory Baseline (3.0 lb/million Btu)	3.0	100	29	3,890	1,180	-	-
Low Sulfur Fuel (0.8 lb/million Btu)	0.8			4,440	320	640	-
Percent Reduction (90 Percent)	3.0/90% FGD			4,470	90	532	130
Combined Cycle Unit W/Credit (129 million Btu/hr)							
Regulatory Baseline (3.0 lb/million Btu)	3.0	100	29	3,890	1,180	-	-
Low Sulfur Fuel (1.6 lb/million Btu)[f]	1.6			4,140	630	455	-
Percent Reduction (87 Percent)[g]	3.0/87% FGD			4,460	120	538	628
Supplementary-Fired							
Mixed Fuel Unit (313 million Btu/hr)							
Regulatory Baseline (3.0 lb/million Btu)	3.0/NG	313	-	13,770[j]	1,180	-	-
Low Sulfur Fuel (0.8 lb/million Btu)	0.8/NG			14,320[j]	320	640	-
Percent Reduction (90 Percent)	3.0/NG			14,460[j]	90	633	609
Combined Cycle Unit W/O Credit (313 million Btu/hr)							
Regulatory Baseline (3.0 lb/million Btu)	3.0	100	213	3,890	1,180	-	-
Low Sulfur Fuel (0.8 lb/million Btu)	0.8			4,440	320	640	-
Percent Reduction (90 Percent)	3.0/90% FGD			4,810	90	844	1,609
Combined Cycle Unit W/Credit (313 million Btu/hr)							
Regulatory Baseline (3.0 lb/million Btu)	3.0	100	213	3,890	1,180	-	-
Low Sulfur Fuel (3.0 lb/million Btu)[h]	3.0			3,890	1,180	0	-
Percent Reduction (69 Percent)[i]	3.0/69% FGD			4,740	330	1,000	1,000

[a]Based on a capacity factor of 0.9.

[b]Average uncontrolled SO_2 emissions.

[c]Annual cost includes only the cost of fuel fired plus the annualized cost of SO_2 control device and does not include other steam generating unit annualized costs.

[d]Compared to regulatory baseline.

[e]Compared to less stringent alternative.

[f]Based on the heat input supplied by the gas turbine exhaust. Credit is calculated as 129/100, or 29 percent. This would translate into an emission limit of 443 ng SO_2/J (1.03 lb SO_2/million Btu). Pricing data are not available, however, for an oil capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 100 percent in order to use available pricing data for an oil meeting a 688 ng SO_2/J (1.6 lb SO_2/million Btu) emission limit.

[g]Based on a 30 percent emission credit.

[h]Based on the heat input supplied by the gas turbine exhaust. Credit is calculated as 313/100, or 213 percent. This would translate into an emission limit of 1,076 ng SO_2/J (2.5 lb SO_2/million Btu). Pricing data are not available, however, for an oil capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 275 percent in order to use available pricing data for an oil meeting a 1,291 ng SO_2/J (3.0 lb SO_2/million Btu) emission limit.

[i]Based on a 210 percent emission credit.

[j]Annualized costs for mixed fuel-fired steam generating units are higher than those for other units examined because the cost of natural gas fuel has been included along with coal fuel costs.

For standards requiring a percent reduction in SO_2 emissions, the incremental cost effectiveness of SO_2 control over standards based on the use of low sulfur fuels is $609/ton for a mixed fuel-fired steam generating unit; $1,609/ton for a supplementary-fired steam generating unit without an emission credit; and $1,000/ton for a supplementary-fired steam generating unit with an emission credit.

This difference in the cost effectiveness of SO_2 control between fully-fired and supplementary-fired steam generating units reflects the fact that the analysis assumes combustion of natural gas in the gas turbine. Since natural gas contains little or no sulfur, the gas turbine exhaust contains little or no SO_2.

As discussed earlier, in a supplementary-fired combined cycle steam generating unit the heat input of the gas turbine exhaust represents about 70 percent of the total heat input to the steam generating unit. Consequently, assuming the gas turbine fires natural gas, the gas turbine exhaust acts as a "diluent", significantly increasing the volume of the flue gases from the steam generating unit without increasing the SO_2 emissions contained in these flue gases. In a fully-fired combined cycle system, the heat input of the gas turbine exhaust only represents about 30 percent of the total heat input to the steam generating unit and the "diluent" effect of the gas turbine exhaust is not as significant. Consequently, assuming the gas turbine fires natural gas, the cost effectiveness of SO_2 control is higher for supplementary-fired combined cycle steam generating units than for fully-fired combined cycle steam generating units.

If, however, the analysis had assumed that oil was combusted in the gas turbine, rather than natural gas, the difference in the cost effectiveness of SO_2 control between supplementary-fired and fully-fired combined cycle steam generating units would narrow. If, for example, the analysis had assumed oil of the same sulfur content was combusted in the gas turbine as in the steam generating unit (which probably represents a more realistic assumption) there would be no difference in the cost effectiveness of SO_2 control between supplementary-fired and fully-fired combined cycle steam

generating units, other than that which might exist due to "economies of scale".

In fact, since the analysis kept the heat input from the fuel fired in the steam generating unit constant, the supplementary-fired steam generating unit is much larger than the fully-fired steam generating unit. As a result, due to "economies of scale", under standards requiring a percent reduction in SO_2 emissions, the analysis would indicate that the cost effectiveness of SO_2 control is lower for a supplementary-fired combined cycle steam generating unit than for a fully-fired combined cycle steam generating unit.

Table 13 summarizes the incremental cost effectiveness of SO_2 control associated with not providing emission credits for fully-fired and supplementary-fired oil-fired combined cycle steam generating units. For standards based on the use of low sulfur fuels, the incremental cost effectiveness of SO_2 control is $968/ton for a fully-fired steam generating unit and $640/ton for a supplementary-fired steam generating unit. For standards requiring a percent reduction in SO_2 emissions, the incremental cost effectiveness of not providing emission credits is $333/ton for a fully-fired steam generating unit and $292/ton for a supplementary-fired steam generating unit.

TABLE 13. INCREMENTAL COST EFFECTIVENESS OF ALLOWING VERSUS NOT PROVIDING EMISSION CREDITS FOR OIL-FIRED COMBINED CYCLE COGENERATION UNITS

	Annualized Cost $1000/yr	Annual Emissions (tpy)	Incremental Cost Effectiveness ($/ton)
Fully-Fired			
Low Sulfur Fuel Standard With Emission Credit (1.2 lb/10^6 Btu)	4,140	630	-
Without Emission Credit (0.8 lb/10^6 Btu)	4,440	320	968
Percent Reduction Standard With Emission Credit (87% FGD/3.0 lb/10^6 Btu)	4,460	120	-
Without Emission Credit (90% FGD/3.0 lb/10^6 Btu)	4,470	90	333
Supplementary-Fired			
Low Sulfur Fuel Standard With Emission Credit (3.0 lb/10^6 Btu)	3,890	1,180	-
Without Emission Credit (0.8 lb/10^6 Btu)	4,440	320	640
Percent Reduction Standard With Emission Credit (69% FGD/3.0 lb/10^6 Btu)	4,740	330	-
Without Emission Credit (90% FGD/3.0 lb/10^6 Btu)	4,810	90	292

5.0 REFERENCES

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2. Laughlin, J. H., J. A. Maddox, and S. C. Margerum. (Radian Corporation). SO_2 Cost Report. Prepared for U.S. Environmental Protection Agency, Research Triangle Park, N. C. EPA Contract No. 68-02-3816. August 10, 1984. p. 2-24.

APPENDIX A

MODEL CASES FOR COMBINED CYCLE COGENERATION SYSTEMS

TABLE A-1. MODEL CASES FOR FULLY-FIRED OIL COMBINED CYCLE COST ANALYSIS - REGION V

Regulation	Unit Type	Boiler Fuel ($lb/10^6$ Btu)	Boiler Heat Input (10^6 Btu/hr)	Gas Turbines Exhaust (10^6 Btu/hr)	Flue Gas Flowrate (acfm)
Baseline	Standard Oil-Fired Boiler	3.0	100	-	30,120
0.8 $lb/10^6$ Btu		0.8	100	-	30,120
90% FGD/0.6 lb 10^6 Btu		0.3	100	-	30,120
Baseline	Mixed Fuel Boiler	3.0/NG	129	-	39,180
1.2 $lb/10^6$ Btu		1.6/NG	129	-	39,180
90% FGD/0.6 $lb/10^6$ Btu		3.0/NG	129	-	39,180
Baseline[a]	Fully-Fired Oil Combined Cycle (MA-1)[c]	3.0	100	29	41,430
0.8 $lb/10^6$ Btu[a]		0.8	100	29	41,430
41,430					
90% FGD/0.6 $lb/10^6$ Btu[a]		3.0	100	29	41,430
Baseline[b]	Fully-Fired Oil Combined Cycle (MA-1)[c]	3.0	100	29	41,430
1.2 $lb/10^6$ Btu[b]		1.6	100	29	41,430
41,430					
87% FGD/0.8 $lb/10^6$ Btu[b]		3.0	100	29	41,430

[a]Combined cycle system without heat input credit.

[b]Combined cycle system with heat input credit.

[c]Refers to the model plant in Reference 1.

TABLE A-2. MODEL CASES FOR FULLY-FIRED COAL COMBINED CYCLE COST ANALYSIS - REGION V

Regulation	Unit Type	Boiler Fuel	Boiler Heat Input (10^6 Btu/hr)	Gas Turbines Exhaust (10^6 Btu/hr)	Flue Gas Flowrate (acfm)
Baseline	Standard Coal-Fired Boiler	E-bit	100	-	36,760
1.2 lb/10^6 Btu		B-bit	100	-	36,740
90% FGD/0.6 lb 10^6 Btu		H-bit	100	-	36,780
Baseline	Mixed Fuel Boiler	E-bit/NG	137	-	48,530
1.2 lb/10^6 Btu		D-bit/NG	137	-	48,460
90% FGD/0.6 lb/10^6 Btu		H-bit/NG	137	-	48,490
Baseline[a]	Fully-Fired Coal Combined Cycle (MF-4A)[c]	E-bit	100	37	51,720
1.2 lb/10^6 Btu[a]		B-bit	100	37	51,720
90% FGD/0.6 lb/10^6 Btu[a]		H-bit	100	37	51,720
Baseline[b]	Fully-Fired Coal Combined Cycle (MF-4A)[c]	E-bit	100	37	51,720
1.2 lb/10^6 Btu[b]		D-bit	100	37	51,720
86% FGD/0.8 lb/10^6 Btu[b]		H-bit	100	37	51,720

[a]Combined cycle system without heat input credit.

[b]Combined cycle system with heat input credit.

[c]Refers to the model plant in Reference 1.

TABLE A-3. MODEL CASES FOR FULLY-FIRED COAL COMBINED CYCLE COST ANALYSIS - REGION VII

Regulation	Unit Type	Boiler Fuel	Boiler Heat Input (10^6 Btu/hr)	Gas Turbines Exhaust (10^6 Btu/hr)	Flue Gas Flowrate (acfm)
Baseline 1.2 lb/10^6 Btu 90% FGD/0.6 lb 10^6 Btu	Standard Coal-Fired Boiler	E-bit B-bit B-bit	100 100 100	- - -	38,845 38,650 38,845
Baseline 1.2 lb/10^6 Btu 90% FGD/0.6 lb/10^6 Btu	Mixed Fuel Boiler	E-bit/NG D-bit/NG B-bit/NG	137 137 137	- - -	50,565 50,565 50,370
Baseline[a] 1.2 lb/10^6 Btu[a] 90% FGD/0.6 lb/10^6 Btu[a]	Fully-Fired Coal Combined Cycle (MG-2)[c]	E-bit B-bit B-bit	100 100 100	37 37 37	53,390 53,390 53,390
Baseline[b] 1.2 lb/10^6 Btu[b] 86% FGD/0.8 lb/10^6 Btu[b]	Fully-Fired Coal Combined Cycle (MG-2)[c]	E-bit D-bit B-bit	100 100 100	37 37 37	53,390 53,390 53,390

[a]Combined cycle system without heat input credit.

[b]Combined cycle system with heat input credit.

[c]Refers to model plant in Reference 1.

TABLE A-4. MODEL CASES FOR SUPPLEMENTAL-FIRED OIL COMBINED CYCLE COST ANALYSIS - REGION V

Regulation	Unit Type	Boiler Fuel ($lb/10^6$ Btu)	Boiler Heat Input (10^6 Btu/hr)	Gas Turbines Exhaust (10^6 Btu/hr)	Flue Gas Flowrate (acfm)
Baseline	Standard Oil-Fired Boiler	3.0	100	-	30,120
0.8 $lb/10^6$ Btu		0.8	100	-	30,120
90% FGD/0.6 lb 10^6 Btu		0.3	100	-	30,120
Baseline	Mixed Fuel Boiler	3.0/NG	313	-	97,590
0.8 $lb/10^6$ Btu		1.6/NG	313	-	97,590
90% FGD/0.6 $lb/10^6$ Btu		3.0/NG	313	-	97,590
Baseline[a]	Supplemental-Fired Oil Combined Cycle	3.0	100	29	278,470
0.8 $lb/10^6$ Btu[a]		0.8	100	29	278,470
90% FGD/0.6 $lb/10^6$ Btu[a]		3.0	100	29	278,470
Baseline[b]	Supplemental-Fired Oil Combined Cycle	3.0	100	29	278,470
3.0 $lb/10^6$ Btu[b]		3.0	100	29	278,470
69% FGD/0.8 $lb/10^6$ Btu[b]		3.0	100	29	278,470

[a]Combined cycle system without heat input credit.

[b]Combined cycle system with heat input credit.

APPENDIX B

SAMPLE CALCULATIONS FOR COMBINED CYCLE COGENERATION SYSTEMS

APPENDIX B

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I. Foreword

In order to determine the cost of SO_2 control for combined cycle systems, the steam generating unit flue gas flowrate had to be calculated. The following calculations demonstrate the procedures used to complete the mass and energy balances for a fully-fired coal combined cycle system. The detailed calculations yield a flue gas flowrate of 49,670 acfm compared to a flowrate of 51,720 acfm for the scaled-down 250 million Btu/hr boiler in the utility combined cycle report.[1] The scaled-down version is 4 percent higher than the flow calculated in detail.

In comparison to a mixed fuel-fired steam generating unit these scaled-down flowrates appeared reasonable for the coal cases. However, the scaled down flowrate for the oil combined cycle cases is significantly higher than the mixed fuel-fired steam generating unit flowrates. After referring back to the utility report we discovered that the utility flowrates were incorrectly based on 35 percent excess air (like coal-fired steam generating units) rather than 10 percent excess air. Therefore, the flowrates shown for the oil combined cycle cases is high. However, flowrates or the supplementary oil-fired units are correct since the flue gas flowrate from these units does not depend on a set excess air. The annual cost of SO_2 control is the cost of the fuel fired in the steam generating unit plus the annualized cost of SO_2 control device.

II. Combustion Calculations -- Fully-Fired Combined Cycle Steam Generating Unit

The gas flows through a fully-fired (stoichiometrically-fired) steam generating unit are reasonably homogeneous. However, as with the gas turbine, it is easier to assume that they are composed of discrete components.[1] The flow diagram of Figure B-1 shows the flow constituents. The inlet gas flows are theoretical air, excess air, and in-leakage air. The exhaust gases are composed of theoretical steam generating unit exhaust,

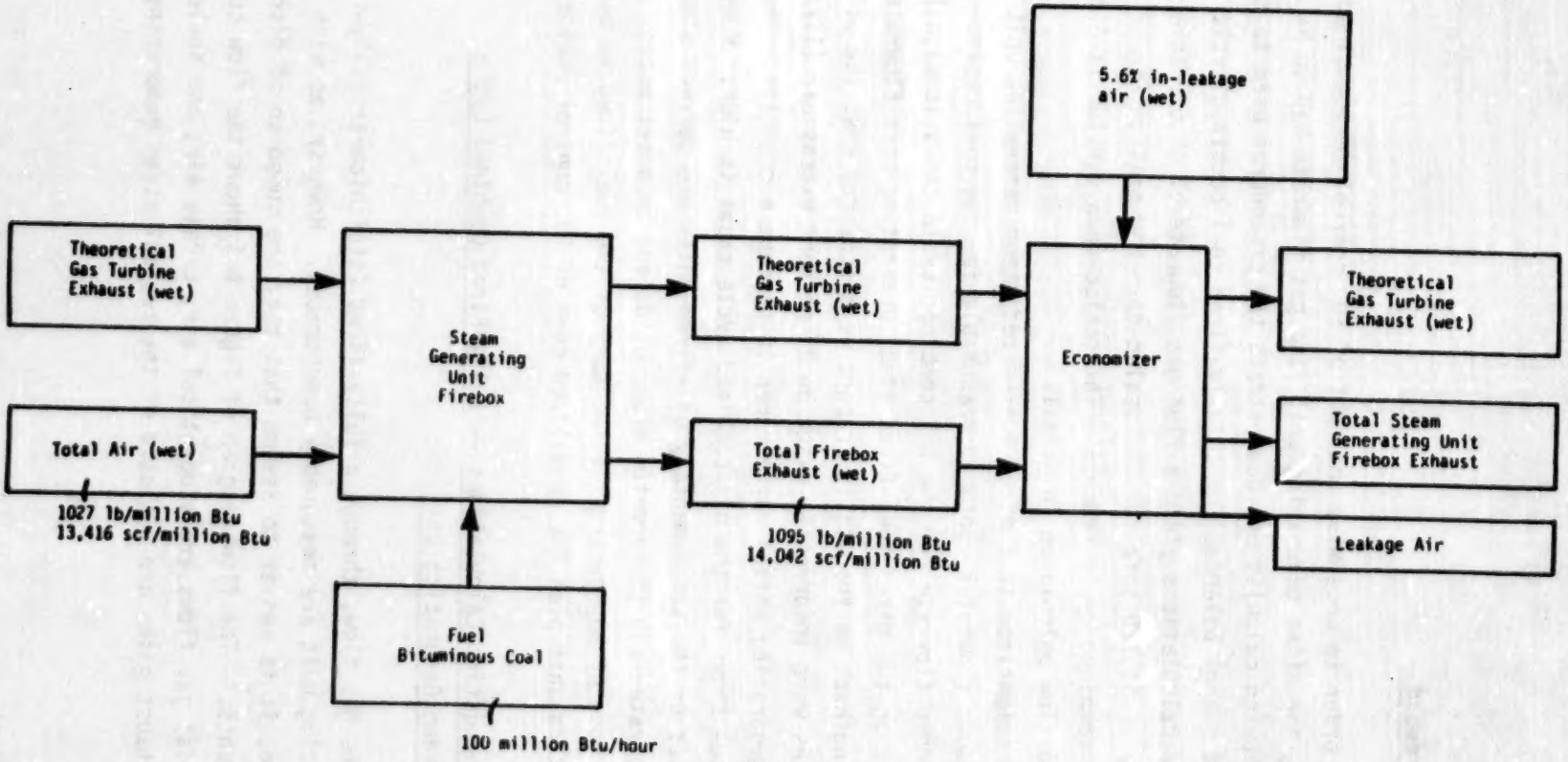

Figure B-1. Flow diagram of a fully-fired combined cycle system.

excess air, and in-leakage air. For these calculations, only flow through the steam generating unit firebox is discussed. All in-leakage air is assumed to occur downstream of the firebox. It is assumed that 35 percent excess air will be used to ensure complete combustion and the steam generating unit is fired with bituminous coal.

A. Fuel Requirement

The fuel selected for the sample steam generating unit is a bituminous coal with the following characteristics:[2]

Heating Value	11,800 Btu/lb
Composition C	64.80 percent by weight
H_2	4.43 percent by weight
N_2	1.30 percent by weight
S	3.54 percent by weight
H_2O	8.79 percent by weight
Ash	10.58 percent by weight
	100.00 percent by weight

B. Air Requirement

The total air requirement of a boiler has two components, theoretical air and excess air. The theoretical is the air actually consumed during 100 percent combustion of the fuel and the excess air is the additional amount required to ensure that complete combustion takes place.

1. Theoretical Air - Theoretical air requirements are set by the composition of the fuel. The air requirements for combustion of the fuel constituents are developed in Table B-1, using the mass rate of the fuel constituent and its combustion constant in air. As shown, the total theoretical air requirement is:

TABLE B-1. STEAM GENERATING UNIT COMBUSTION CALCULATIONS THEORETICAL AIR REQUIREMENTS[4]
(USING WEIGHT METHOD, ASSUMING BITUMINOUS COAL)

Fuel Constituent	Ultimate Analysis, As Fired (Weight Percent)	Combustion Constants (lbs/lbs Constituent)		Theoretical Air Required for Combustion (lbs Air/lbs Fuel)
		O_2	Air	
C	64.80	2.66	11.53	7.471
H_2	4.43	7.94	34.34	1.521
O_2	6.56	--		-
N_2	1.30	--		-
S	3.54	1.00	4.29	0.152
H_2O	8.79	--		-
Ash	10.58	--		-
	100.0			9.144[a]
Less O_2 in Fuel (deduct)				-0.283[a]
Theoretical Air Requirements				8.861
Total Air Requirements Assuming 35 Percent Excess Air (1.35 x Theoretical Air)				11.962
Excess Air (11.962 - 8.861)				3.101

[a]Air equivalent of O_2 in fuel.

$$\text{Theoretical Air}_{dry} = 8.861 \text{ lbs air/lb fuel}$$

2. Total Air - The steam generating unit is assumed to operate with 35 percent excess air. Thus:

$$\text{Total Air}_{dry} = 135\% \times 8.861 = 11.962 \text{ lbs air/lb fuel}$$

but ambient air contains water vapor. The moisture content of air at standard conditions (60 percent R.H. and 80°F) is 0.013 lb water/lb air[2], so:

$$\text{Total Air}_{wet} = 11.962 + [0.013 \times 11.962]$$
$$= 12.12 \text{ lbs air/lb fuel}$$

or, in terms of heat input:

$$\text{Total Air}_{wet} = \frac{12.12 \text{ lbs air/lb fuel}}{11{,}800 \text{ Btu/lb fuel}} \times 10^6 = 1027 \text{ lbs}/10^6 \text{ Btu}$$

Air obeys the perfect gas laws, so one mole of air has a volume of 379 ft^3 at standard temperature and pressure.[3] Thus:

$$\text{Total Air}_{vol} = \text{Total Air}_m \times \frac{\text{Molar Volume}}{\text{Molecular Wt. of Air}}$$

$$= \frac{1027}{10^6} \text{ lb} \times \frac{379 \text{ ft}^3/\text{mol}}{29 \text{ lb/mol}} = 13{,}416 \text{ scf}/10^6 \text{ Btu}$$

C. Products of Combustion

The products of perfect combustion of a fuel are CO_2 and H_2O. In addition, the exhaust gases contain the other constituents of the air and fuel, in either reacted or non-reacted form.

Combustion Calculations - Combustion calculations for solid fuels are usually performed on a weight basis. The combustion product calculations, are shown in Table 2. The flue gas produced by complete combustion of the fuel in 35 percent excess air is:

Steam Generating Unit Flue Gas_m = 12.9188 lbs air/lb fuel

or,

Steam Generating Unit Flue Gas_m =

$$\frac{12.9188 \text{ lb}}{\text{lb Fuel}} \times \frac{\text{lb fuel}}{11{,}800 \text{ Btu}} = 1094.8 \text{ lbs}/10^6 \text{ Btu}$$

The molecular weight (MW) of the steam generating unit flue gas is the sum of the combustion products of steam generating unit combustion, which is determined from Table B-2 as follows:

Product of Combustion	Fuel Analysis Weight percent	Molecular Weight	Fuel Analysis mole percent
CO_2	2.372 lbs/lb fuel	44.01 lb/mol	0.0539 moles/lb fuel
H_2O	0.554 lbs/lb fuel	18.02 lb/mol	0.0308 moles/lb fuel
SO_2	0.071 lbs/lb fuel	64.06 lb/mol	0.0011 moles/lb fuel
O_2	0.718 lbs/lb fuel	32.0 lb/mol	0.0224 moles/lb fuel
N_2	9.204 lbs/lb fuel	28.02 lb/mol	0.329 moles/lb fuel
	12.919 lbs/lb fuel		0.4372 moles/lb fuel

The molecular weight of the steam generating unit flue gas is thus:

$$MW_{fg} = \frac{\text{Weight of Combustion Products}}{\text{Moles of Combustion Products}}$$

$$= \frac{12.9188 \text{ lbs/lb fuel}}{0.4372 \text{ moles/lb fuel}} = 29.55 \text{ lb/mol}$$

The steam generating unit flue gases are assumed to obey the perfect gas law. The volume of the steam generating unit flue gases are therefore:

TABLE B-2. STEAM GENERATING UNIT COMBUSTION CALCULATIONS -- PRODUCTS OF COMBUSTION[a] (USING WEIGHT METHOD)

Constituent	Ultimate Analysis, As-Fired (lb/100 lb Fuel)	Product of Combustion	Combustion Constant (lb Product/lb Constituent)	Combustion Products (lb/lb Fuel)
Fuel:				
C	64.80	CO_2	3.66	2.37
H_2	4.43	H_2O	8.94	0.40
O_2	6.56	-[b]	-	0.0
N_2	1.30	N_2	1.0	0.013
S	3.54	SO_2	2.0	0.071
H_2O	8.79	H_2O	1.0	0.088
Ash	10.58	-[c]	-[c]	-
	100.0			2.94
Air:[d]				
O_2	204. (Theoretical)	-[b]	-	0.0
	72. (Excess)	O_2	1.0	0.72
N_2	920.			9.2
	1196.			9.92

[a]Assuming 35 percent excess air.

[b]Assumes O_2 consumed during combustion.

[c]Ash is not included as a product of combustion for the purposes of this calculation.

[d]N_2 in air = 76.85 weight percent, O_2 in air = 23.15 weight percent.

$$\text{Steam Generating Unit Flue Gas}_v \times \frac{\text{Molal Volume}}{\text{MW of Flue Gas}}$$

$$= \frac{1094.8 \text{ lbs}}{10^6 \text{ Btu}} \times \frac{379 \text{ ft}^3/\text{mol}}{29.55 \text{ lb/mol}} = 14{,}042 \text{ scf}/10^6 \text{ Btu}$$

III. Sample Calculations -- Combined Cycle Model Plant with Fully-Fired Steam Generating Unit

The sample model plant is a combined-cycle plant having a fully-fired steam generating unit fired at 100 million Btu/hr with bituminous coal. The combustion air requirements of the steam generating unit are exactly matched by the excess air content of the turbine exhaust.

A. Given

Steam generating unit heat input (from fuel)	100 million Btu/hr
Heating value of steam generating unit fuel (bituminous coal)	11,800 Btu/lb
Gas temperature entering steam generating unit firebox[6]	1000°F
Gas temperature entering steam generating unit firebox and economizer[6]	700°F
Gas temperature entering steam generating unit at economizer exit[6]	300°F
Heat content of gas turbine exhaust	621,051 lb/10^6 Btu[1]
Gas turbine excess air	1774.1 lb/10^6 Btu[1]
Steam generating unit air	1027 lb/10^6 Btu (See II.B.2)

B. Fuel Use

1. Gas Turbine - The excess air (EA) in the gas turbine exhaust exactly matches the total air (TA) requirements of the steam generating unit

(no gas turbine exhaust bypass and no supplementary source of combustion air):

$$\text{Gas Turbine Excess Air} = \text{Steam Generating Unit Total Air}$$

$$\text{Gas Turbine Excess Air} = \frac{1774.1 \text{ lb}}{10^6 \text{ Btu}} \times \text{Gas Turbine Heat Input}$$

$$\text{Steam Generating Unit Total Air} = \frac{1027 \text{ lb}}{10^6 \text{ Btu}} \times \text{Steam Generating Unit Heat Input}$$

Therefore, for a Steam Generating Unit Heat Input of = 100 million Btu/hr:

$$\text{Gas Turbine Heat Input} = \frac{1027 \text{ lb}/10^6 \text{ Btu}}{1774.1 \text{ lb}/10^6 \text{ Btu}} \times 100 \text{ MM Btu/hr}$$

$$= 57.9 \text{ million Btu/hr}$$

2. Boiler - The heat input to the sample steam generating unit is 100 MM Btu/hr of a bituminous coal with a heating value of 11,800 Btu/lb, so:

$$\text{Steam Generating Unit Fuel}_R = \frac{\text{Steam Generating Unit Value}}{\text{Fuel Heating Value}}$$

$$= \frac{100 \times 10^6 \text{ Btu/hr}}{11{,}800 \text{ Btu/lb}} = 8475 \text{ lb/hr}$$

C. Heat Input From Gas Turbine

The heat input of the gas turbine exhaust entering the steam generating unit firebox is 621,051 Btu/10^6 Btu[1] and the gas turbine heat input is 57.9 MM Btu/hr, so the heat input to the sample steam generating unit is:

$$\frac{621{,}051 \text{ Btu}}{10^6 \text{ Btu}} \times \frac{57.9 \text{ million Btu}}{\text{hr}} = 35.96 \text{ million Btu/hr}$$

D. Gas Flows

1. Steam Generating Unit Firebox Inlet - The total air requirements of the sample fully-fired steam generating unit is assumed to exactly match the gas turbine excess air (no gas turbine exhaust bypass and no supplementary combustion air). Thus, the presence of the theoretical gas turbine exhaust gas increases total gas flow through the steam generating unit firebox.

Steam Generating Unit Total Air = Gas Turbine Excess Air

The steam generating unit air requirement is 1027 lb/million Btu (see II.B.2) and the steam generating unit fuel input is 100 million Btu/hr:

$$\text{Steam Generating Unit Air} = \frac{1027 \text{ lb}}{10^6 \text{ Btu}} \times \frac{100 \text{ million Btu}}{\text{hr}} = 102{,}700 \text{ lb/hr}$$

Also: Steam Generating Unit Inlet Gas = Total Gas Turbine Exhaust[1]

Therefore:
$$\frac{\text{Steam Generating Unit Gas}}{\text{Steam Generating Unit Air}} = \frac{\text{Total Gas Turbine Exhaust}}{\text{Gas Turbine Excess Air}}$$

$$\frac{\text{Steam Generating Unit Gas}}{102{,}700 \text{ lb/hr}} = \frac{275.8 \text{ lb}/10^6 \text{ Btu to Gas Turbine}}{1774.1 \text{ lb}/10^6 \text{ Btu to Gas Turbine}}$$

$$\text{Steam Generating Unit Inlet Gas} = \frac{2547.8}{1774.1} \times 102{,}700 = 147{,}488 \text{ lb/hr}$$

The theoretical gas turbine (G.T.) exhaust contribution to this total is:

G.T. Theoretical Exhaust = Steam Generating Unit Inlet Gas - Steam Generating Unit Total Air

G.T. Theoretical Exhaust = 147,488 lb/hr - 102,700 lb/hr = 44,788 lb/hr

As noted earlier, the gas flow into the firebox of a combined cycle steam generating unit is the gas turbine exhaust and the gas turbine excess

air, which is also the steam generating unit total air requirement. The molecular weight of the gas turbine theoretical exhaust is 27.5 lb/mol[1], so its volume is:

$$\text{G.T. Theoretical Exhaust}_{vol} = \text{G.T. Theoretical Exhaust}_{m} \times \frac{\text{molar volume}}{\text{MW of G.T. Exhaust}} = \frac{44{,}788 \text{ lb/hr}}{60 \text{ min/hr}} \times \frac{379 \text{ ft}^3\text{/mol}}{29.53 \text{ lb/mol}} = 9580 \text{ scfm}$$

The steam generating unit total air volume is 13,416 scf/10^6 Btu (see II.B.2).

$$\text{Steam Generating Unit Air}_{vol} = \frac{13{,}416 \text{ scf}}{10^6 \text{ Btu}} \times \frac{100 \text{ million Btu}}{60 \text{ min/hr}} = 22{,}360 \text{ scfm}$$

The volume of the total gas flow entering the steam generating unit firebox is thus:

$$\text{Steam Generating Unit Gas}_{vol} = \text{G.T. Theoretical Exhaust}_{v} + \text{Steam Generating Unit Total Air} = 9580 \text{ scfm} + 22{,}360 \text{ scfm} = 31{,}940 \text{ scfm}$$

At 1000°F, the density correction factor is 0.36[7], so:

$$\text{Steam Generating Unit Inlet}_{v} = \frac{31{,}940 \text{ scfm}}{0.36} = 88{,}722 \text{ acfm @ } 1000°\text{F}$$

2. Steam Generating Unit Firebox Exhaust (to Economizer) - The total exhaust gas from the steam generating unit firebox is the sum of the inputs:

Steam Generating Unit Inlet Gas.....147,488 lb/hr
Steam Generating Unit Fuel.....+8475 lb/hr (see II.B.2.)
Steam Generating Unit (Firebox)
Exhaust Gas.....155,963 lb/hr

The steam generating unit flue gas component of this total is:

Steam Generating Unit Exhaust Gas.....155,963 lb/hr
Theoretical Gas Turbine Exhaust.....-44,788 lb/hr
Steam Generating Unit Flue Gas_m.....111,175 lb/hr

The volume of the steam generating unit flue gas is 14,042 scf/10^6 Btu (see II.A.3)

$$\text{Steam Generating Unit } Gas_v = \frac{14{,}042 \text{ scf}}{10^6 \text{ Btu}} \times \frac{100 \text{ million Btu/hr}}{60 \text{ min/hr}} = 23{,}403 \text{ scfm}$$

And the total volume of gas leaving the steam generating unit firebox is:

Steam Generating Unit Exhaust Gas_v = Steam Generating Unit Flue Gas_v +
G.T. Theoretical Exhaust = 23,403 scfm + 9580 scfm = 32,983 scfm

At 700°F the density correction is 0.46[7], so:

$$\text{Steam Generating Unit Exhaust } Gas_v = \frac{32{,}983}{0.46} \text{ scfm}$$

$$= 71{,}702 \text{ acfm @ } 700°F$$

3. Economizer Exhaust - All in-leakage of air to the combined cycle steam generating unit is assumed to occur in the economizer. The amount of leakage is assumed to be 5.6 percent of the inlet gas to the boiler, or:

$\text{In-leakage Air}_m = 0.056 \times 31{,}940 \text{ scfm} = 1{,}789 \text{ scfm}$

Thus, the total gas flow from the economizer is:

	Mass	Volume
Steam Generating Unit Exhaust Gas.....	155,963 lb/hr	32,983 scfm
In-leakage Air.....	+ 8,259 lb/hr	+ 1,789 scfm
Economizer Exhaust.....	164,222 lb/hr	34,772 scfm

At 300°F, the density correction factor is 0.70^{7}, so:

$$\text{Economizer Exhaust} = \frac{34{,}772 \text{ scfm}}{0.70} = 49{,}679 \text{ acfm @ } 300°\text{F}$$

APPENDIX B REFERENCES

1. Utility Combined Cycle Report, Appendix B.
2. Taken From Background Information Document, Fossil Fuel Boilers, pp. 3-26.
3. Steam, 37th Edition, p. 4-9.
4. Steam, 37th Edition, p. 4-5, 6.
5. Steam, 37th Edition, p. 4-8.
6. Steam, 37th Edition, p. 4-2.
7. EPRI FP-862, Combustion Turbine Repowering of Reheat Steam Power Plants, Dated 8/78, p. 3-40.
8. AP-40, Air Pollution Engineering Manual, 2nd Edition, p. 58.